2. Gas Productive Capacity

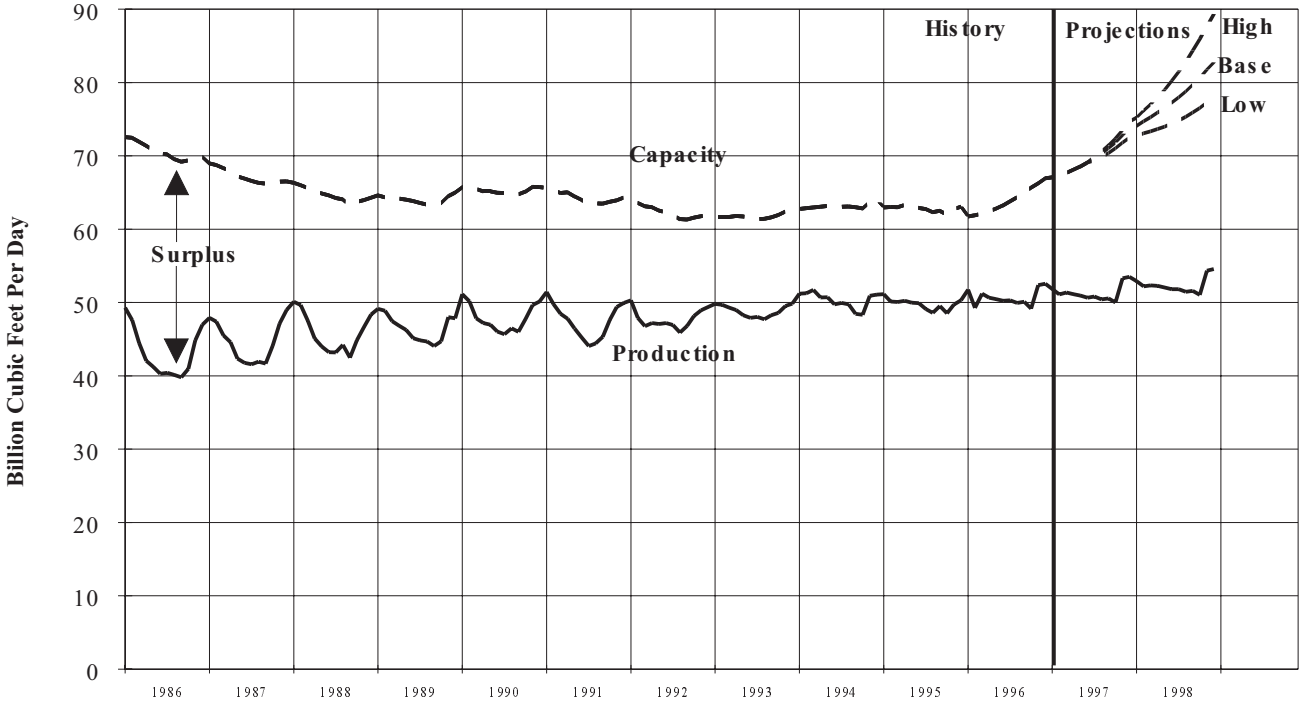
Gas Capacity to Meet Lower 48 States Requirements

The United States has sufficient dry gas productive capacity at the wellhead to meet forecast monthly production requirements through 1998 (Figure 1). Any potential shortfalls in States with low productive capacity could probably be met by transfers from those areas with a large surplus productive capacity, such as the Gulf of Mexico Outer Continental Shelf (OCS).

Dry gas is the type of gas generally transported by transmission systems and delivered to customers. *Gross gas* is the full stream volume, including all natural gas plant liquids and nonhydrocarbon gases but excluding lease condensate. In 1995, dry gas production represented 89 percent of the gross gas production in the lower 48 States (Figure 2).

For reporting and analysis, the lower 48 States were grouped into 10 separate producing States or areas on the basis of gas production volumes (Figure 3). Dry gas productive capacity was determined for each of these 10 areas. The quarterly gas production forecast in the Energy Information Administration (EIA), Short-Term Integrated Forecasting System, August 1997 {12} was used to determine the lower 48 States' production. This production was prorated into the 10 areas on the basis of their historical market shares. The quarterly production was further prorated into monthly data. If a given area could not meet its historical market share of production, the unmet production requirements were prorated to areas with surplus productive capacity. It was assumed that the pipeline facilities exist to transport this additional production from another supply area to its end market. Recent historical production patterns were used to allocate the projected lower-48 gas production requirements for 1997 and 1998 among States and areas (Figure 4).

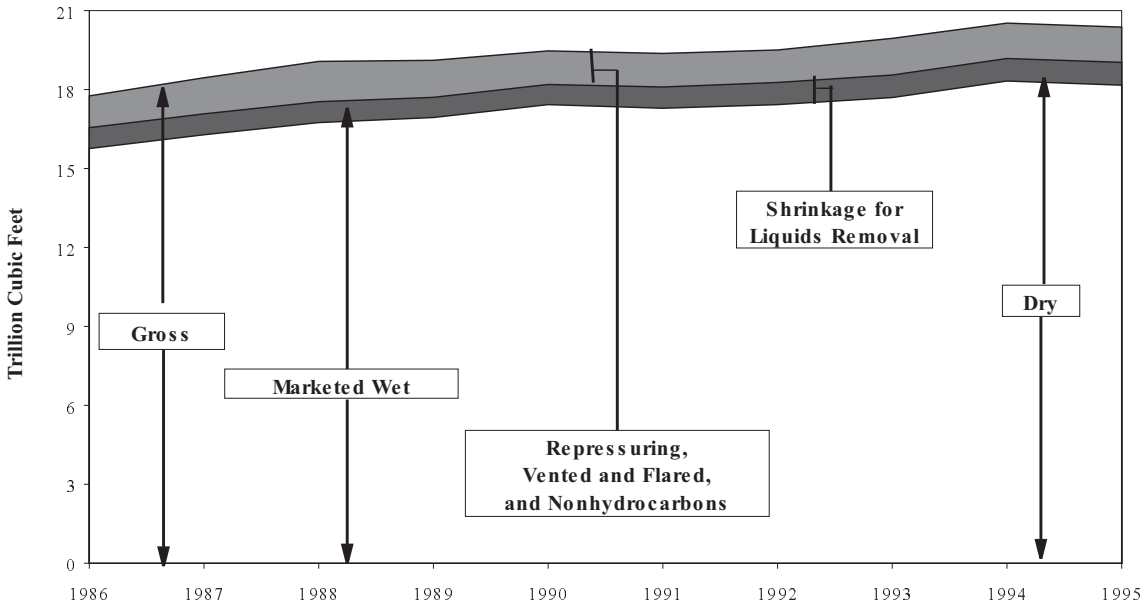
Figure 1. Lower 48 States Dry Gas Monthly Production Rate and Wellhead Productive Capacity, 1986-1998



Note: Production projection plotted for base case only. The 1996 estimated history is based on Model GASCAP94 C102997 projections.

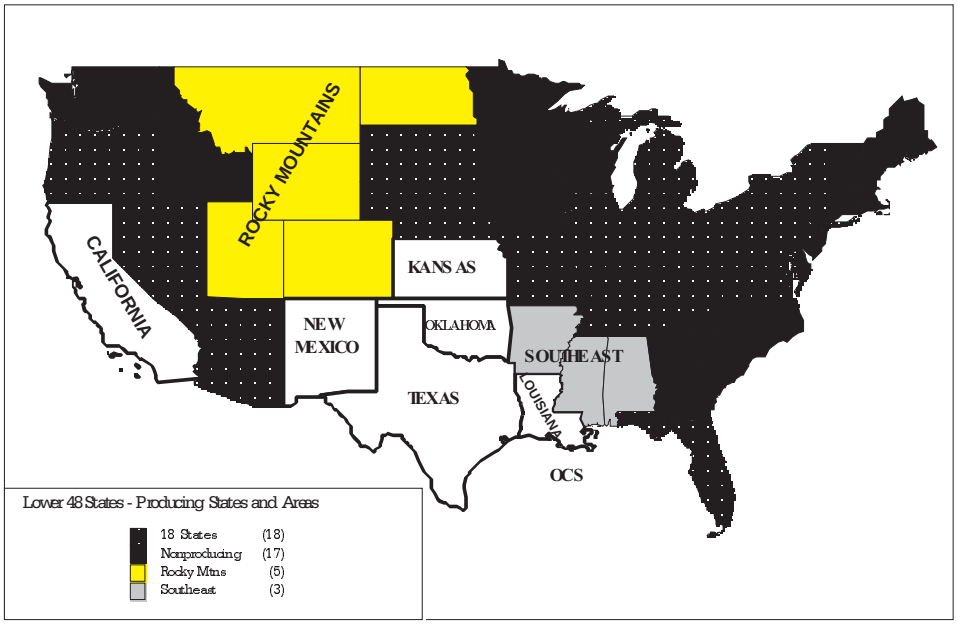
Sources: Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP94 C102997. Productive Capacity: Model GASCAP94 C102997. Production Projections: Energy Information Administration, Short-Term Integrated Forecasting System, August 1997, and Model GASCAP94 C102997.

Figure 2. Lower 48 States Natural Gas Production, 1986-1995



Source: Energy Information Administration, *Natural Gas Annual*, DOE/EIA-0131, 1986-1995.

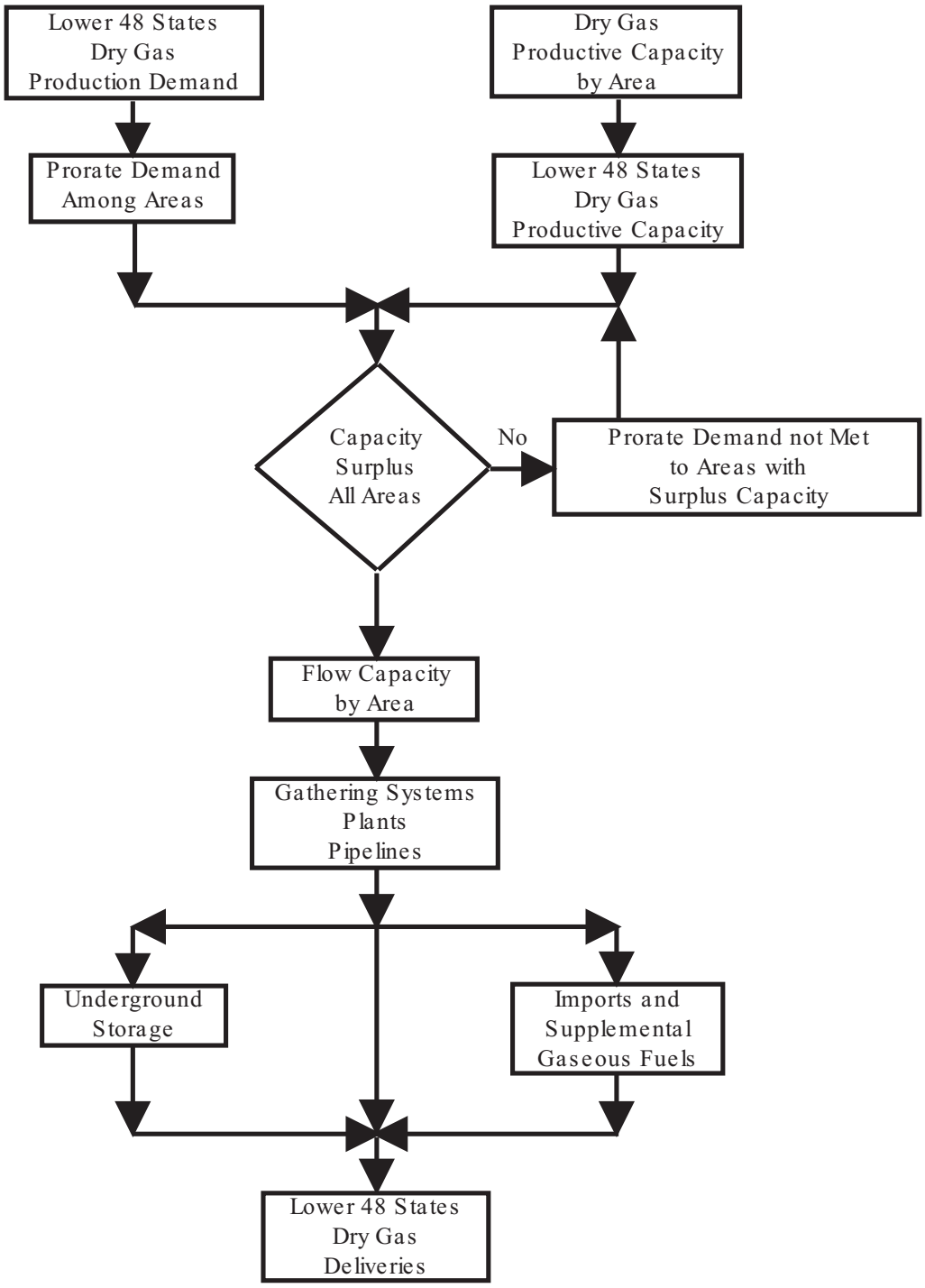
Figure 3. Lower 48 States - Producing States and Areas



Note: The 18 States are Arizona, Florida, Illinois, Indiana, Kentucky, Maryland, Michigan, Missouri, Nebraska, Nevada, New York, Ohio, Oregon, Pennsylvania, South Dakota, Tennessee, Virginia, and West Virginia. Non-producing States are Connecticut, Georgia, Delaware, Idaho, Iowa, Maine, Massachusetts, Minnesota, New Jersey, New Hampshire, North Carolina, Rhode Island, South Carolina, Vermont, Washington, and Wisconsin. Rocky Mountain States are Colorado, Montana, North Dakota, Utah, and Wyoming. Southeast States are Alabama, Arkansas, and Mississippi.

Source: Energy Information Administration, Office of Oil and Gas.

Figure 4. Lower 48 States Productive Capacity and Supply Schematic



Source: Energy Information Administration, Office of Oil and Gas.

Historical Data

Dry Gas Productive Capacity Trends

Historical monthly gas production and productive capacity for the lower 48 States for the months of January, June, and December are presented in Table 1.[1] January and December represent the typical peak winter months, and June represents a non-heating season.

Dry gas productive capacity in the lower 48 States substantially exceeded production throughout the 1980's. The lower 48 States' surplus capacity was more than 20 billion cubic feet per day through December 1986. However, gas capacity began declining in 1986 as drilling and new well completions rapidly declined. In 1996, surplus capacity was 14.4 billion cubic feet per day in December of that year.

The rapid decline in drilling and new well completions was caused by reduced natural gas prices. The wellhead price for natural gas shows a declining trend in 1986 and most of 1987 and then begins fluctuating seasonally after 1987 (Figure 5).

Gas Production

Total gross gas production (composed of gas-well and oil-well gas) from 1986 through 1995 is shown in Figure 6. Gas production from oil wells was stable over this time period, although oil production declined. Increases in producing gas-oil ratios roughly compensated for the declines in oil production. In 1995, gas production from oil wells was 16 percent of total gas production in the lower 48 States. If oil production declines in 1996, 1997, and 1998, as expected, gas production from oil wells will also decline if the producing gas-oil ratio stays at its 1995 level. The share of total gross production from gas wells increased from 79 percent in 1986 to 84 percent in 1995.

The dry natural gas production contribution from the major gas-producing States and areas is shown by Figure 7. The market share of production among States has been fairly stable from 1986 through 1995. The two largest gas-producing areas are the Gulf of Mexico OCS and Texas. Together these areas produce over one-half of the dry gas in the lower 48 States. The Gulf of Mexico has made the largest contribution to meeting major seasonal swings in demand. Other significant natural gas-producing States include Oklahoma, Louisiana, New Mexico, and Kansas. Chapter 3 reviews State and area gas production in detail.

Monthly gas production varies seasonally. Normally, production is highest in the months of January or February (because of high heating demand), substantially lower in June, and relatively higher in December. However, the minimum monthly production rate for a given year may fall in other months, such as September, when there is neither a large cooling nor heating demand.

Coalbed gas was treated separately in this report for New Mexico and the Southeast and Rocky Mountains areas (Figure 8). These are the three major coalbed gas-producing areas. Coalbed gas production was 5 percent of the lower-48 total gas produced in 1995.

Gas Prices

The average real wellhead value of natural gas peaked in 1983 at $3.75 (in constant 1995 dollars) per thousand cubic feet{13}, dropped sharply in 1986, and continued to decline to $1.76 per thousand cubic feet in 1991 (a 52 percent drop over eight years). The average price in 1995 is $1.55.{14} For comparison, real domestic crude oil prices dropped from $38.52 per barrel in 1983 to $14.62 in 1995, a 62 percent drop.{13} Given the lower prices and consequent decrease in drilling, it is understandable that wellhead productive capacity declined to values closer to gas production requirements from 1986 through 1995.

Projections

Dry Gas Productive Capacity and Production

EIA projects the natural gas wellhead productive capacity for the lower 48 States by using the *Wellhead Productive Capacity Model*. For a description of the model, see Appendix A. The model estimates the last year of historical production and productive capacity (because the data is still preliminary) and generates a 2-year projection of production and wellhead gas capacity. To account for unpredictable market forces and changing drilling activity levels, gas productive capacity projections are formulated for *low*, *base*, and *high* cases. The *base* case reflects what would most likely occur if current market trends continue and drilling and production levels continue to perform as they have performed in the past. The *high* case reflects an increase in the amount of drilling under more favorable market conditions, while the *low* case reflects a decrease under less favorable conditions. The model results are listed in Table 2.

In December 1996, the wellhead productive capacity of the lower 48 States was 66.9 billion cubic feet per day of dry natural gas. For the lower 48 States, the model projects the following:

- In the *low* case projection, dry gas productive capacity will increase 16 percent to 77.9 billion cubic feet per day in December 1998.

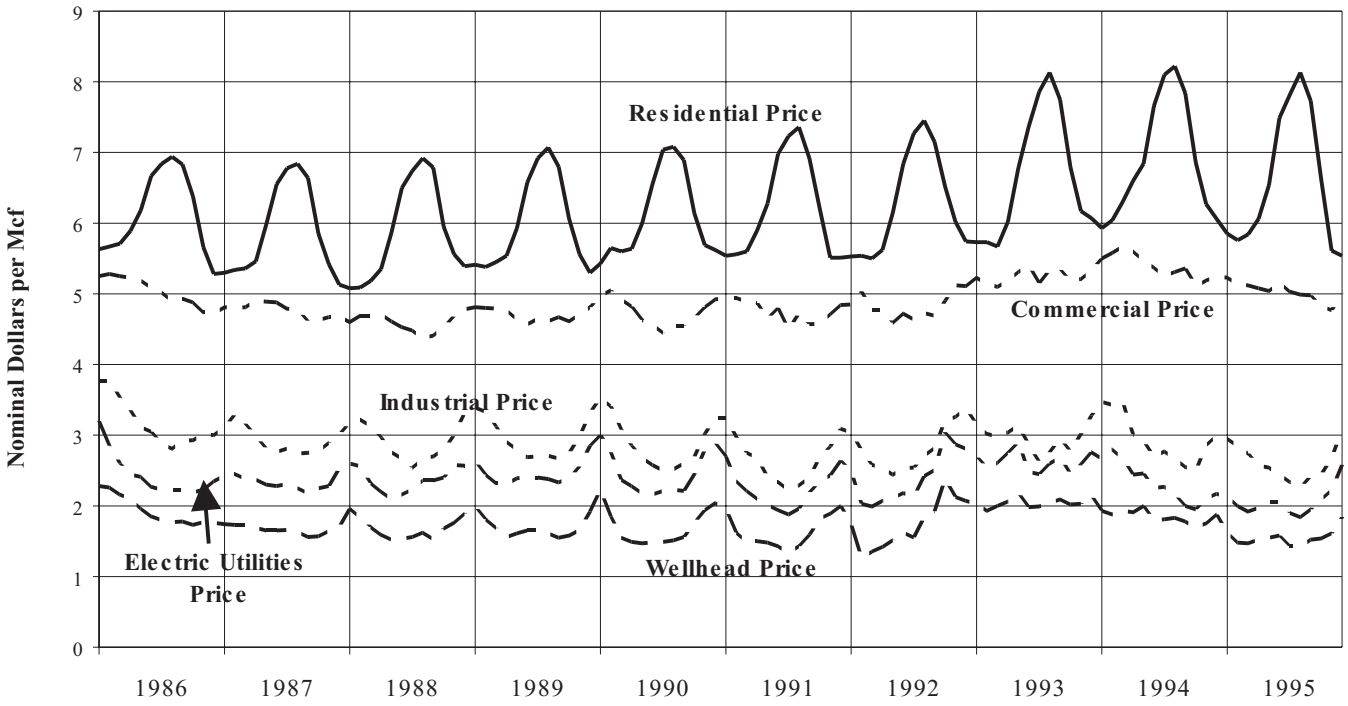
[1] Production and capacity for all 12 months can be obtained from the authors.

Table 1. Lower 48 States Dry Gas Production and Wellhead Productive Capacity, 1986-1996
(Billion Cubic Feet Per Day)

		Dry Gas Productive Capacity				
Month-Year	Dry Production	Gas-Well Gas	Oil-Well Gas	Total Gas	Total Surplus	Utilization (percent)
Jan-86	49.3	62.7	9.8	72.6	23.3	67.9
Jun-86	40.3	61.3	9.0	70.3	30.0	57.3
Dec-86	47.0	61.1	8.8	69.9	22.9	67.2
Jan-87	47.9	60.0	9.0	69.0	21.1	69.4
Jun-87	41.8	58.1	8.8	66.9	25.1	62.5
Dec-87	49.0	57.8	8.7	66.5	17.5	73.7
Jan-88	50.1	57.5	8.8	66.3	16.2	75.6
Jun-88	43.2	55.8	8.8	64.6	21.4	66.9
Dec-88	48.4	55.7	8.5	64.3	15.9	75.3
Jan-89	49.1	55.8	8.8	64.6	15.5	76.0
Jun-89	45.1	55.4	8.4	63.8	18.7	70.7
Dec-89	47.8	57.1	7.9	65.0	17.2	73.5
Jan-90	51.1	57.0	8.7	65.7	14.6	77.8
Jun-90	46.0	56.6	8.4	65.0	19.0	70.8
Dec-90	50.1	57.3	8.4	65.7	15.6	76.3
Jan-91	51.4	57.2	8.4	65.6	14.2	78.4
Jun-91	45.2	55.7	8.3	64.0	18.8	70.6
Dec-91	49.9	56.0	8.3	64.3	14.4	77.6
Jan-92	50.3	55.3	8.6	63.9	13.6	78.7
Jun-92	47.2	53.9	8.4	62.3	15.1	75.8
Dec-92	49.4	53.6	8.2	61.9	12.5	79.8
Jan-93	49.8	53.5	8.1	61.7	11.9	80.7
Jun-93	47.9	53.5	8.1	61.6	13.7	77.8
Dec-93	49.8	54.6	7.9	62.6	12.8	79.6
Jan-94	51.2	54.7	8.0	62.8	11.6	81.5
Jun-94	49.8	55.2	7.9	63.1	13.3	78.9
Dec-94	51.1	56.1	8.0	64.1	13.0	79.7
Jan-95	51.1	55.2	7.8	63.0	11.9	81.1
Jun-95	49.9	55.1	7.8	62.9	13.0	79.3
Dec-95	50.3	55.3	7.7	63.0	12.7	79.8
Jan-96	51.8	54.0	7.7	61.7	9.9	84.0
Jun-96	50.2	55.6	7.7	63.3	13.1	79.3
Dec-96	52.6	59.1	7.8	66.9	14.3	78.6

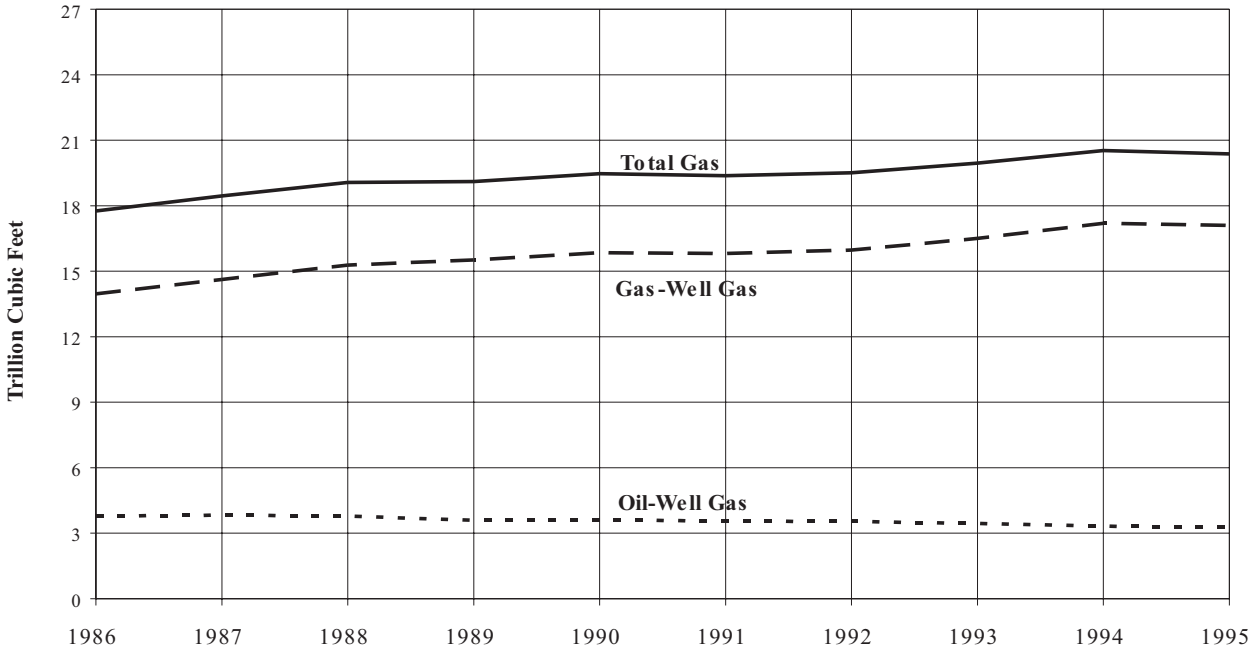
[a]The 1996 estimated history is based on Model GASCAP94 C102997 projections and Baker Hughes rig counts.
Sources: Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP94 C102997. Productive Capacity: Model GASCAP94 C102997.

Figure 5. Natural Gas Price by Category, 1986-1995



Source: Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130(97/04)

Figure 6. Lower 48 States Gross Natural Gas Production by Type, 1986-1995



Source: Energy Information Administration, *Natural Gas Annual*, DOE/EIA-0131, 1986-1995

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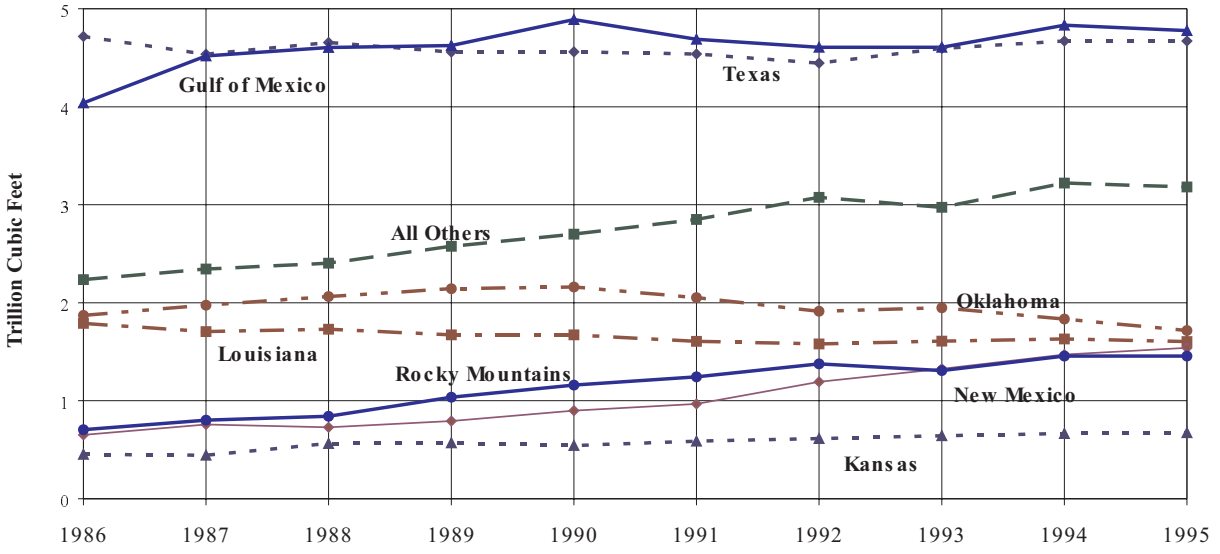
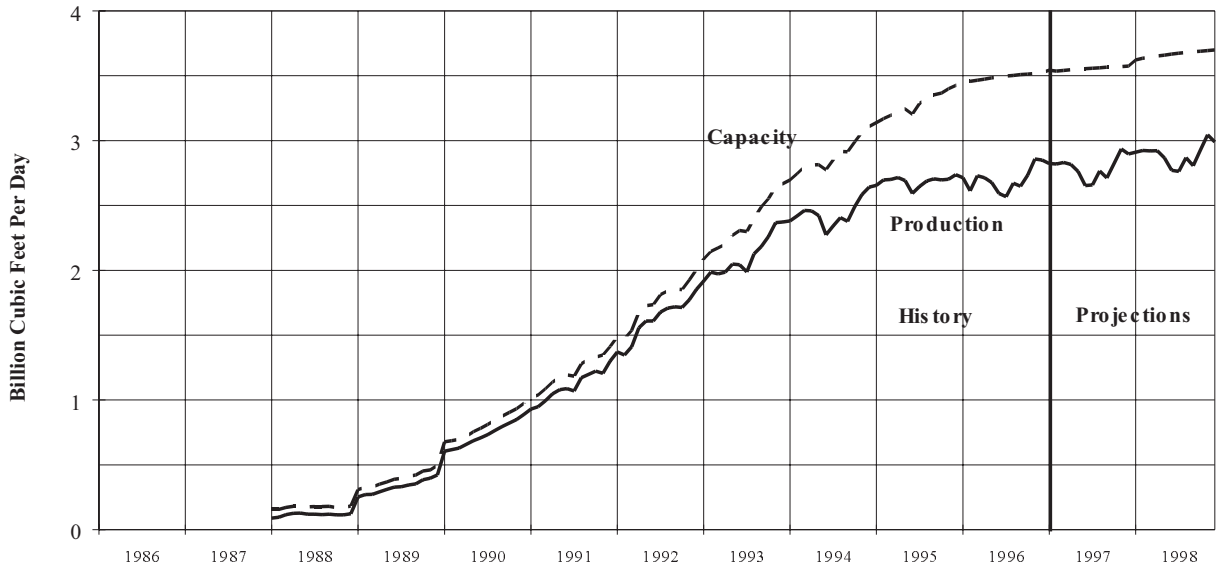
Figure 7. Dry Natural Gas Production from Lower 48 Producing States, 1986-1995



Note: State production for Texas and Louisiana does not include Gulf of Mexico OCS production

Sources: Energy Information Administration, *Natural Gas Annual*, DOE/EIA-0131, 1986-1995. Data for Texas, Louisiana, and Gulf of Mexico OCS are from Energy Information Administration, Office of Oil and Gas.

Figure 8. Lower 48 States Dry Coalbed Gas Monthly Production Rate and Wellhead Productive Capacity, 1986-1998



Note: Production projection plotted for base case only.

Sources: Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP94 C102997. Productive Capacity: Model GASCAP94 C102997. Production Projections: Energy Information Administration, Short-Term Integrated Forecasting System, August 1997, and Model GASCAP94 C102997.

Table 2. Lower 48 States Dry Gas Production and Wellhead Productive Capacity Projections, 1997-1998 (Billion Cubic Feet Per Day)

Month-Year	Dry Production	Dry Gas Productive Capacity				
		Gas-Well Gas	Oil-Well Gas	Total Gas	Total Surplus	Utilization (percent)
			Low Case Projection			
Jan-97	51.8	59.2	7.8	67.1	15.3	77.2
Jun-97	50.7	61.4	7.7	69.1	18.4	73.4
Dec-97	53.5	65.2	7.3	72.5	19.0	73.8
Jan-98	52.9	65.4	7.3	72.7	19.8	72.8
Jun-98	51.8	67.3	7.1	74.4	22.6	69.6
Dec-98	54.6	71.0	7.0	77.9	23.3	70.1
			Base Case Projection			
Jan-97	51.8	59.2	7.8	67.1	15.3	77.2
Jun-97	50.7	61.4	7.7	69.1	18.4	73.4
Dec-97	53.5	66.1	7.6	73.7	20.2	72.6
Jan-98	52.9	66.4	7.6	74.1	21.2	71.4
Jun-98	51.8	69.7	7.6	77.3	25.5	67.0
Dec-98	54.6	75.3	7.5	82.7	28.1	66.0
			High Case Projection			
Jan-97	51.8	59.2	7.8	67.1	15.3	77.2
Jun-97	50.7	61.4	7.7	69.1	18.4	73.4
Dec-97	53.5	66.7	7.9	74.6	21.1	71.7
Jan-98	52.9	67.3	7.9	75.2	22.3	70.3
Jun-98	51.8	72.3	7.9	80.2	28.4	64.6
Dec-98	54.6	81.4	8.0	89.3	34.7	61.1

Sources: Production Projections: Energy Information Administration, Short-Term Integrated Forecasting System, August 1997 and Model GASCAP C102997. Productive Capacity Projections: Model GASCAP94 C102997.

- In the *base* case projection, productive capacity will increase 24 percent to 82.7 billion cubic feet per day in December 1998.
- In the *high* case, productive capacity increases 33 percent from the December 1996 level, reaching 87.3 billion cubic feet per day in December 1998.

For surplus capacity in the lower 48 States:

- In the *low* case, the surplus capacity increases from 14.4 billion cubic feet per day in December 1996 to 23.3 billion cubic feet per day in December 1998.
- In the *base* case, surplus capacity increases to 28.2 billion cubic feet per day in December 1998.
- In the *high* case, the surplus capacity increases to 34.8 billion cubic feet per day in December 1998.

Gas productive capacity should be adequate to meet the projected monthly gas production requirements of the lower 48 States through December 1998, even in the *low* case.

New Well Completions

Gas productive capacity is increased by new gas-well completions. If there had been no new gas-well completions projected after 1995, the surplus capacity would have gone from 14.4 billion cubic feet per day in December 1996 to zero by December 1997. With no new completions, productive capacity would not have been adequate to meet the forecast production requirements. Gas-well completions must be added continuously to sustain an adequate productive capacity.

To project gas productive capacity, a projection of new gas-well completions is required. The projection of new well completions is based on a projection of rigs running and an estimate of completions per rig. Forecasts of the total drilling rigs were obtained from the EIA Drilling Rig Model. This model generates monthly rig counts on the basis of oil and gas revenues which are derived from production and price data appearing in the EIA's *Short Term Energy Outlook* (STEO). The Drilling Rig Model was described in previous reports{1,2,3,4,5}.

Gas-well completions added for the 2-year period 1997 through 1998 are estimated to be 34,939 for the *low* case, 39,342 for the *base* case, and 46,039 for the *high* case (Figure 9). The larger number of completions yields a dry gas productive capacity for the *high* case in December 1998 that is 89.3 billion cubic feet per day, (Table 2) or 8 percent higher than the 82.7 billion cubic feet per day in the *base* case. Gas production requirements were assumed to be the same in both cases. A new gas-well completion is estimated to add about one million cubic feet per day of capacity (Appendix C).

For the *low*, *base*, and *high* cases, the corresponding gas-well completions were estimated primarily as a function of gas price and production. The 1998 gas prices for the three cases were respectively $1.66, $2.23, and $2.63 per thousand cubic feet, as shown in the Short-Term Integrated Forecasting System, August 1997{12}. The actual gas prices were $1.55 per thousand cubic feet in 1995{14} and $2.17 in 1996{12}.

The newer gas-well completions contribute most of the productive capacity in the lower 48 States. Wells less than three years old contributed 49 percent of the productive capacity in the lower 48 States in December 1996. Wells less than 2 years old provided 40 percent, while wells completed that year provided 28 percent (Figure 10).

Gas Productive Capacity Issues

Demand

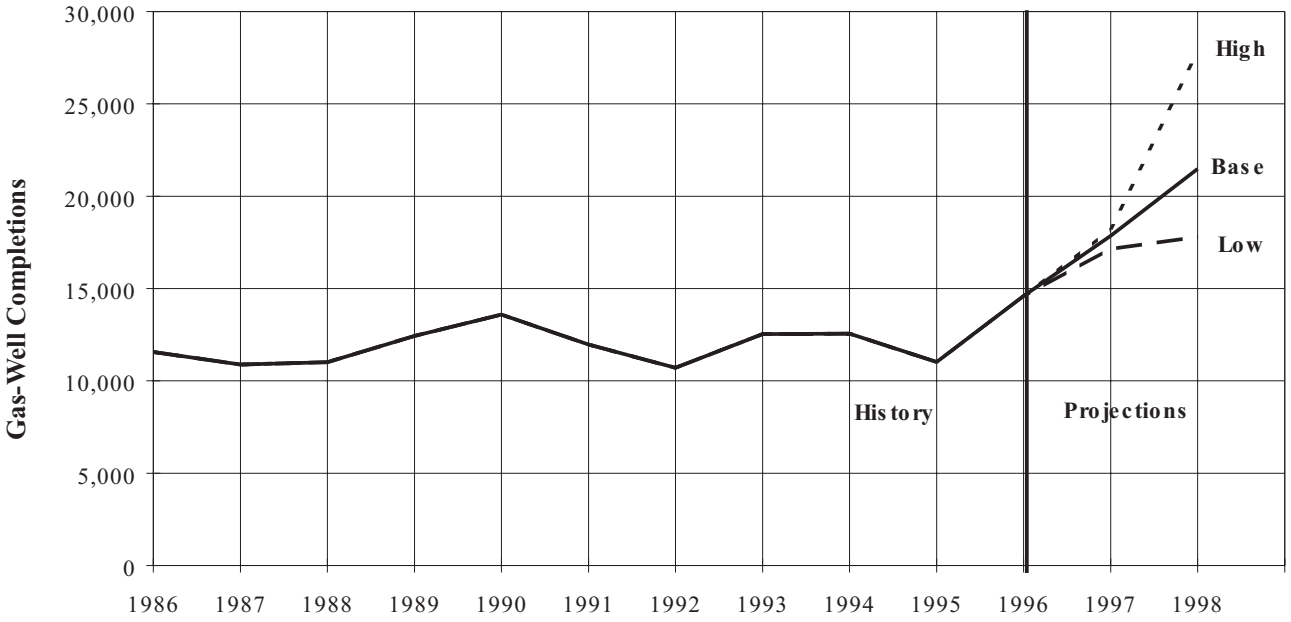
Peak-day demand may be twice the annual average-day demand. Peak-day demand usually occurs in December, January, or February during very cold weather. The cold weather, while increasing gas demand, may also decrease potential supply because of weather-related production and transportation problems.[2]

Peak-day demand cannot be met by increasing gas production at the wellhead and should not be expected to be met by production in the future. To better serve its customers, the natural gas industry has developed methods to meet peak demand, such as delivery from gas storage facilities and peak shaving facilities.

It could be argued that in periods of high gas demand, price increases at the wellhead could both increase supply quantities and decrease consumption until they balance. Over a sufficient period of time this is true. However, in the very short term (days), average wellhead prices are relatively unresponsive to demand, although, commercial, industrial, and electric utility gas prices normally increase during periods of high seasonal demand (Figure 5). The vast majority of gas is covered by 30-day or longer contracts. Therefore, if there is a sudden large increase in gas demand, there is not an accompanying sudden, large increase in the average price of gas at the wellhead. However, small volumes of gas may sell at very high prices on the spot market.

[2]For more information about this subject see Energy Information Administration, Service Report SR/OG/91-01 and Oil and Gas Journal, March 5, 1990, pp.17-20.

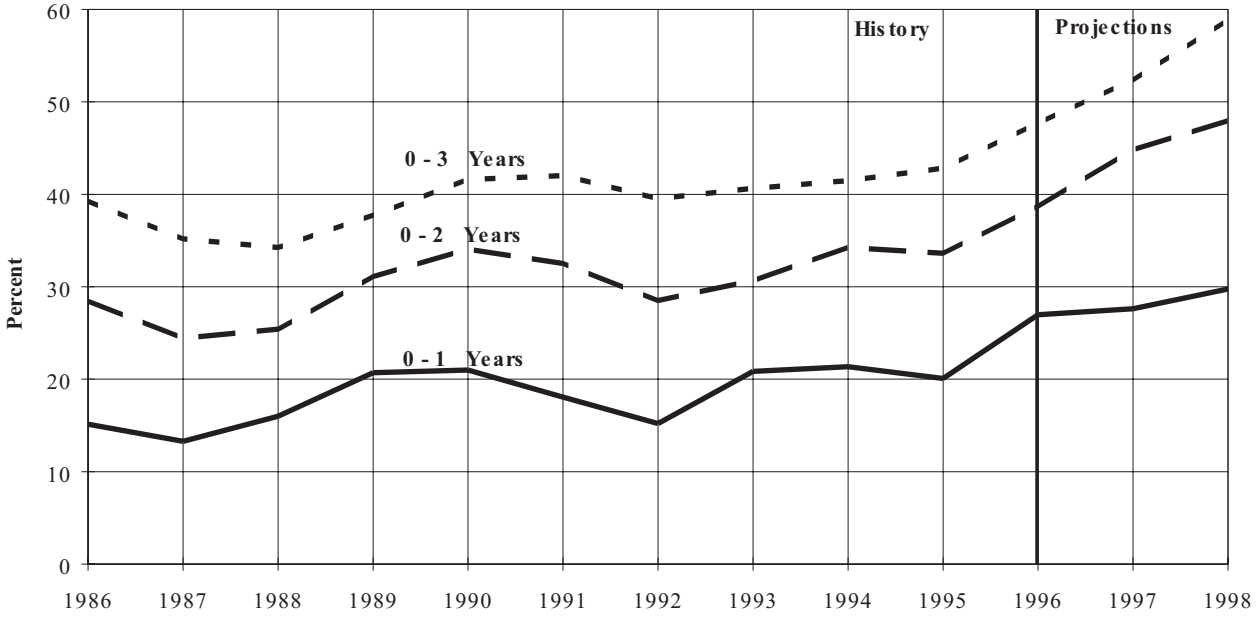
Figure 9. Lower 48 States Gas-Well Completions Added During Year, 1986-1998



Note: The 1996 estimated history is based on EIA's Drilling Rig Model projections and Baker Hughes rig counts. Completions include recompletions in new producing zones.

Sources: History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc. Projections: Model GASCAP94 C102997.

Figure 10. Percent of Total Wellhead Productive Capacity of Lower 48 States Gas Wells (Minus the 18 States Group) by Well Age, 1986-1998 (Base Case)



Sources: History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc. Projections: Model GASCAP94 C102997.

Effective gas demand in peak periods is typically lowered by reducing deliveries to customers with interruptible contracts or by customers with fuel-switching capability responding to higher gas prices by switching to another fuel. A price increase would have little impact on reducing residential gas requirements. It is residential heating or cooling demand that is most likely to have a sudden upward surge related to weather. Residential consumers used 5.2 times as much gas in December 1994 as they did in August 1994 and 6.6 times as much gas in December 1995 as they did in August 1995.{15}

Because cost-of-service pricing lowers the unit cost of gas during periods when large volumes are being delivered, the residential cost of gas per thousand cubic feet actually drops in December, while the wellhead price of gas increases.{15} Figure 5 shows the relationship of wellhead price to residential, commercial, industrial, and electric utility prices for 1986 through 1995. Therefore, small increases in the average price of natural gas at the wellhead do not effectively dampen weather-related residential gas requirements in the short term.

Deliverability

The existence of a high gas productive capacity at the wellhead does not mean that it could actually be produced and delivered. Deliverability is always equal to or less than wellhead productive capacity. Deliverability takes into account restrictions imposed by pipeline capacity, contract, or regulatory bodies. Even with a large surplus dry gas productive capacity, there can be Short-Term regional gas supply problems.

In order to meet peak-month or peak-day demand, the pipeline system must also have adequate deliverability to the final destination. Pipeline systems must have adequate diameters, properly spaced compressors, and adequate interconnections between pipelines. Gas pipeline systems must be optimized to transport gas efficiently from any well to wherever in the lower 48 States where the need might arise.

Productive capacity and deliverability can be compared by using the data collected by the Natural Gas Supply Association (NGSA) in its NGSA Survey on 1995 Natural Gas Field Deliveries & Productive Capacity.{16} The data on connected gas-well capacity as of January 1, 1996, which is equivalent to deliverability into the pipeline system, were collected on an operator basis for seven lower-48 regions. The survey covered 83 percent of the production for the Offshore Gulf Coast, the highest for any region in the survey. The ratio of the NGSA 1995 connected gas field capacity to the annual 1995 field deliveries was 1.07. In other words, deliverability was 7 percent higher than annual production. The equivalent deliverability for all Offshore Gulf Coast operators was 15 billion cubic feet per day if the NGSA surveyed operators are representative of all operators in this region.

For the month of January 1996, it was estimated that 85 percent of the productive capacity at the wellhead could be delivered into the pipeline system. This was obtained by dividing the January 1996 deliverability of 53 billion cubic feet per day (determined by scaling up the NGSA connected-gas-well capacity){16} by the January 1996 dry productive capacity at the wellhead of 62 million cubic feet per day.

During the 1980's and most recently with FERC Order 636 in 1992, major changes have occurred in regulations, contracts, interconnections between trunklines, access to transportation, and markets. These changes have introduced a much greater degree of flexibility and responsiveness in the natural gas industry. This flexibility makes it likely that a higher percentage of the productive capacity can be delivered. More gas can get from where it is produced to where it is needed. However, in some cases, pipeline capacity may limit gas deliverability.

Weather's Effect on Deliverability

One problem that is associated with the handling of natural gas is the phenomenon of a production line or well “freezing up.” This problem occurs when water vapor and hydrocarbon vapors combine to form snow-like substances, called hydrates. Under suitable pressure conditions, hydrates may be formed at temperatures well above the freezing point of water. One of the problems in handling natural gas is the prevention of the formation of hydrates and their removal once formed.

Interruptions in regional supply can cause a peak production requirement in other areas. For example, storms in the Gulf of Mexico have damaged producing sites and abruptly shut in wells. Needed gas was supplied to consumers from other areas or from storage during part of this time.

Gas Storage

Gas storage is a vital part of the natural gas industry. Stored gas provides a source for reliable deliveries during periods of heavy demand. Storage also enables greater system efficiency by allowing more stable production and transmission flows.

Sufficient dry gas productive capacity will exist during the years 1997 through 1998 to increase the underground natural gas storage inventory needed. Gas storage requirements can be met by maintaining gas production closer to gas productive-capacity throughout the year. Increased use of storage reduces the need for excess productive capacity, thus promoting improved economic efficiency in production.

Imports

Imports have become an increasingly important part of the domestic gas supply picture. Reliance on imported gas has more than doubled in less than a decade. In 1986, net imports made up 4 percent (689 billion cubic feet) of the total gas demand requirements. In 1995, net imports supplied 12 percent (2,687 billion cubic feet) of the total gas demand requirements.